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London, 24 June 2022

Locational Pricing Assessment – Call for input following first stakeholder session (26th May 2022)

Thank you for the opportunity to provide input into the modelling assumptions that FTI and Ofgem will use when making their locational pricing assessment.

EPEX SPOT operates a power exchange in Great Britain, Central Western Europe, the Nordic countries and Poland, providing a market place for companies to trade electricity. EPEX SPOT facilitates trading in a transparent manner, according to public rules and publicises prices which serve as a benchmark for the wholesale and retail markets, as well as for the OTC market. EPEX SPOT provides a liquid market place for producers, suppliers, system operators and industrial consumers, to fulfil their energy requirements in short term power.

Whilst we appreciate the difficulty in running a stakeholder engagement exercise on such a complex topic, it is important to allow sufficient time to prepare and provide feedback. Material was only provided a few days in advance which were then talked through at speed in the workshop. This is not conducive to receiving effective feedback.

The quantitative assessment presented is likely to see short cuts in the assumptions in the modelling. Through limiting the model’s scope it will restrict the quality and relevance of the analysis. This will limit the ability to draw conclusions or will end up being self-fulfilling. We note that FTI already claim in the slides that some designs are already outside of the scope of work or the visibility of National Grid ESO.

Given the scope of work, it appears that to ease the modelling complexity, the assumptions will ignore the critical elements moving to net zero: distributed generation, storage and demand side response. This analysis should be ambitious, reflecting the expected growth of decentralised energy. Overall, if the study wants to conclude on the ability of the nodal design to be more fit for the energy transition and Net zero it should properly take into account the intermittent and decentralized nature of the power grid into the central dispatch. This does not seem to be the case with the current modelling limitations.

(1) The key opportunities associated with introducing more granular locational pricing in GB

Tackling grid congestions and unlocking the potential of demand-side flexibility are key challenges of the energy transition. Due to the development of renewable energies, such congestions have been rising on the transmission and distribution levels.

Nodal is sound theoretically but its implementation is based on the model developed in the 1980s and implemented in the 1990s and 2000s in some US states/markets. Instead, developing local flexibility markets on the distribution level, incorporating coordination with the ESO to manage the impact on the transmission network, can create an opportunity to promote DSR, prosumers and distributed connected generation without resorting to a full market redesign

Local flexibility markets at the distribution level can complement grid development through tackling the challenge of grid congestions by making best use of system flexibilities. Flexibility markets centralise local flexibility offerings. They allow network operators to resolve physical congestions and flexibility providers benefit from an additional revenue opportunity without having to move towards a central dispatch system which is rigid, administrative/bureaucratic/monopolistic and characterised by inertia. Squeezing the entire system complexity that is driven by the decentralization into one single algorithm that handles the grid, asset and market complexity will not be fit for the Net zero future.

(2) The key implementation challenges, risks and mitigations

There are significant challenges to moving to the nodal market. We believe that the complexity is significantly underestimated by FTI and National Grid ESO.

We will leave it to others, who are better placed, to describe the implementation challenges that they would face as energy companies having to operate in a new market. However, as a market operator with experience in developing trading systems and algorithms on the transmission and distribution level, we believe that there are key points that EPEX SPOT is qualified to comment on.

First, we understand that the distributed grid will not be considered despite the growth of distributed connected assets. We also understand, although it is not clear to us, that demand side response will not be exposed to LMP. These are essential components of the energy transition and yet they are excluded from being assessed.

Secondly, we are concerned that storage will be modelled (particularly with the exclusion of distributed-connected storage assets) in a simplistic manner that will hide the computational challenge that incorporating storage presents. This is a major concern in current nodal markets in the US. The slides suggest that the model will aggregate storage capacity and subsequently smear the capacity across nodes/zones essentially giving each node one very large battery. This simply will not reflect the operational load on the algorithm. Solving for thousands of batteries across time and location becomes incredibly complex. This could lead to compromise over products, stranded (or underutilised) assets and a lack of return on investment. We would like to understand how this assessment will consider this implementation challenge? If this is ignored then there is a danger of designing a market that is built for a fleet of assets that more closely resembles the markets of 20 years ago.

Accompanying the complexity that nodal faces with RES and storage, we are also concerned that central dispatch concentrates the challenge in a single company via central dispatch. This will create a monolithic entity in the GB system that is responsible for the entire market. It will crowd out innovation and create a single point of failure. Alternative models offer more resilience through allowing access to a more routes to markets.

Changing the rules under which investors have signed off projects will harm investments already made and deter investors from doing anything further until the rules are clarified. There is a risk, that investors would prefer more stable markets in the EU. Rules will need to be established around existing support mechanisms but beyond that what markets are expected to evolve to facilitate hedging? To determine the impact on investment this analysis should explain the value proposition to organisations looking to invest beyond the limited assessment on congestion.

Finally, clarity is needed regarding how interconnectors are going to be modelled in the analysis. It is unclear how nodal is compatible with the commitments in the TCA whereby the UK and EU are working towards delivering efficient trading arrangements through multi-regional loose volume coupling. The efficient use of the interconnectors is critical to realise the benefits that interconnectors have in terms of making the GB system more robust and flexible particularly given the stated Government aim of reaching 18 GW of interconnector capacity by 2030. The impact on multipurpose interconnectors, revenues and the revenue support mechanism should be an essential output of this work.

(3) The proposed approach to modelling zonal and nodal market designs.

Further written feedback based on the materials presented

Session 1	
Slide 15	**Have we captured all the key impacts from transitioning to a locational market design?** *How are you going to assess industry costs? Please capture the costs such as the changing law, market framework and implementation costs for all organisations and not just National Grid ESO and Ofgem.* *Lot of parameters must be aligned between market parties and National Grid ESO. This is significant amount of work that industry will need to resource to ensure a well-functioning market. It is not only technical costs. There are some benchmarks from US for the nodal transition that suggest the cost can be in the billions. Transitioning is much more significant than shown here. Impact on IT systems, metering infrastructures etc.*
Slide 16	**Have we captured all relevant stakeholder groups and appropriately disaggregated (slide 14)?** *Are DNOs considered?*
Slide 18	*Nodal prices - assumed determined in the short-term dispatch model - will have a tremendous role in the determination of investment decisions - that are made using the long-term capacity expansion model and build-out assumptions.* ○ *How does the long-term model accommodate the location of assets?* ○ *How is the consistency between those short-term and long-term models ensured?* ○ *How will the influence of nodal prices impact the investment in transmission and distribution networks be captured?*
Slide 20-21	**What are your views on the locational disaggregation we should model?** *Need to think about the target vision rather than the grid as it is today. This is limited by the number of nodes only at the transmission substation. It should include the distributed level.* *Option 3 of the nodal model with individual storage assets modelled should be the minimum to make this exercise worthwhile.* *10k nodes is creating fit for future market design. We found the cons irrelevant for reasons for not proceeding with the analysis. We would expect the needs case to be readily developed.*
Slide 22	**What are your views on the scenarios we should model?** *It appears that this redesign of the market is attempting to mask the late building out of the grid. Once the grid is developed in the most constrained areas it appears that the constraint costs will decline.* *We also question the relevance of implementation nodal markets, as the key expected benefits will already be delivered by grid building out within the same timeframe.*

Session 2	
Slide 27	What are your views on transmission post-2041? *We do not have a strong view, but presumably given the limited options presented each scenario could be produced relatively easily.*
Slide 30-31	**What are your views on how generation capacity should be forecasted?** *Storage should be modelled on a per unit basis rather than smeared over the nodes/zones. Whilst providing a more robust model, it will also give an indication of the complexity of calculation and be able to analyse the impact of generation location on the investments. Not doing so will hide how complex it is to optimise many units across time and location. It will hide the implementation and operational complexity leading to a market design that can not be practically delivered to meet the desired outcomes.* *We will need to understand the assumption behind what capacity is available and how the model will determine which assets will be activated to meet demand. Will RES + storage make the majority?*
Slide 36	**What are your views on our approach to modelling CfD contract holders?** *How realistic is it to assume that locational prices will allow efficient siting of new generation? There should be a friction (or inefficiency) reflecting that siting of assets can not be purely driven by the LMP. We'd also argue that some of the pricing of assets includes expected constraint payments. How is that impact expected to be assessed fairly within the modelling?*
Slide 37	**What are your views on the potential impacts of locational pricing on the cost of capital?** *We'd be interested to learn how the proposed FTR market (to solve the volatility) is expected to develop. We note that liquidity will be via hubs but liquidity takes time develop and investors need a history of prices in order to sign-off investments. A risk that is not mentioned that until the market settles there will be a hiatus in investment when it is desperately needed. Is that scenario modelled?*
Slide 39	What are your views on (1) our proposed sensitivities; and (2) other sensitivities we should include; and (3) which sensitivity is a high priority? *How will you assess the computational implementation and operational challenge of developing a nodal market. Plexos will only be a proxy of the nodal market – how will the study assess modelling and computational sensitivities around how the nodal algorithm would run in real-world simulations?* *High priority:* *(i) report of computational KPIs.* *(ii) number of storage assets* *It is critical that extensive sensitivity analysis is an output of this work. The reasoning provided (lack of time and computational complexity) is not a credible given it's such a critical decision for GB's power market.* *Locational price exposure to demand should not be considered as a sensitivity but be included in the main analysis.*

	Additional sensitivities, including a comparison with the zonal case, should also be considered to capture: - *the impact of different models of hedging – as they would in turn impact investment and short-term pricing* - *take into account different weather scenarios. This is key in case of strong penetration of renewables.* - *the robustness of proposed market design when stressed (commodity prices, unavailability of key assets…) – this is especially important, knowing the current events in the Australian power market.* - *the robustness of prices and dispatch with different levels of renewables and storage (and associated uncertainties)* - *the robustness of the model using different market participant behaviour. An additional case modelling non-competitive market behaviour is also necessary to bring trust to the market: how easy are they to detect, what would be their impact*

Session 3	
Slide 43	Have we missed any policies that would likely be impacted by the introduction of more granular locational pricing?
	Which are the priorities to explore as part of this assessment?
	Do you agree with our initial assessment of likely policy impacts?
	Which are you most concerned about?